Methodology and Assumptions

Overview

This study modeled a post-combustion amine-based carbon capture plant on a theoretical Steam Assisted Gravity Drainage (SAGD) facility. The objective of this study was to evaluate how project economics are impacted by two different systems supplying steam and/or power to the capture plant:

1. An auxiliary boiler that generates steam for the capture plant.
2. A combined heat and power (CHP) plant that supplies both steam and electricity to the capture plant.

The study involved process simulations using Aspen HYSYS and Thermoflow software. Capital Expenditure (CapEx), Operating Expenditure (OpEx), Levelized Cost of Capture (LCOC), and Levelized Cost of CO_2 Avoided (LCOA) of different cases were compared based on Association for the Advancement of Cost Engineering (AACE) Class 5 estimates.

Operating Conditions of the Capture Plant

This model assumed a plant availability of 90% (7,884 hours per year). A 10% steam margin was assumed to support capturing and compressing 95% of CO_2 emissions from the existing SAGD facility and the auxiliary boiler or the CHP plant.

Simulation Tools

Thermoflow was used for the auxiliary boiler and CHP plant thermodynamic simulations, while Aspen HYSYS was used for the process simulation of the capture plant. The HYSYS model included key process equipment for CO_2 capture, solvent regeneration, dehydration, compression and associated water treatment and cooling systems. It was assumed that the capture plant used an amine blend of monoethanolamine (MEA) and methyl diethanolamine (MDEA).

Flue Gas Composition for the Existing Facility

The existing SAGD facility was assumed to generate 1 million tonnes of CO_2 per year. The flue gas composition from the existing facility is outlined below.

Table 1. Flue Gas Composition from Existing Facility

Parameter	Unit	Value
Flue Gas Pressure	bar	0.94
Flue Gas Temperature	°C	160
H_2O	% mole	16.4
N_2	% mole	71.4
Ar	% mole	1.1
O_2	% mole	2.5
CO_2	% mole	8.5
SO_2	ppmv	2.5
SO_3	ppbv	4.0
NO	ppmv	24
NO_2	ppmv	1.0

Scenario Descriptions

For all scenarios, it was assumed that an electric CO_2 compressor was used. The CO_2 dehydration for all scenarios was based on the Triethylene process.

The first scenario supplied steam to the capture plant using a natural-gas fired auxiliary boiler. The capture plant was designed to capture CO_2 emissions from both the existing SAGD facility and the auxiliary boiler. All electricity for the capture plant was purchased from the grid.

The CHP plant scenarios supplied both steam and electricity to the capture plant. Excess power generated by the CHP plant was sold to the grid. The capture plant was designed to capture CO_2 emissions from both the existing SAGD facility and the CHP plant. Three CHP plant scenarios were evaluated to assess the impact of integrated steam and power generation:

1. **CHP1**: A CHP plant capable of producing 90 MW
2. **CHP2**: A CHP plant capable of producing 117 MW
3. **CHP3**: A CHP plant capable of producing 201 MW

Determining CapEx and OpEx for the Capture Plant

The CapEx of different cases were estimated using Aspen Capital Cost Estimator (ACCE) based on AACE Class 5 estimates. This included direct field costs, indirect field costs, and non-field costs (taxes, permits, other project costs, escalation), in addition to contingency.

Both fixed and variable OpEx were evaluated in this project. The fixed OpEx in the analysis considered the costs of:

- Labour and support
- Property taxes, insurance, and contingency

- Operations and operating consumables
- Maintenance costs

The variable OpEx considered all utility and chemical consumptions, such as amine, chemicals, fuel, and/or electrical power.

Determining By-Product Revenue

This study showed that excess electricity generated by CHP plants provides a meaningful revenue stream for projects. It's important to highlight that this revenue stream can vary based on regional market conditions. To quantify this revenue, our model assumed a value of **CAD $75.00/MWh** for excess electricity sold to the grid. Nominal power prices were estimated based on historical data, and the Alberta Electrical System Operator's supply and demand forecasts.

Determining the LCOC and LCOA

To assess the economic viability of a carbon capture project, it is important to determine the LCOC and LCOA. This model assumed the construction period of the capture plant, auxiliary boiler or CHP plant, and balance of plant to be three years. The capital cost distribution was considered as 10%, 60%, and 30% from January 2027 through to December 2029. The first year of operation was assumed to be 2030, with OpEx projected over 25 years of capture plant operation. The assumptions used for the LCOC and LCOA calculation are listed below.

Table 2: Assumptions used for LCOC and LCOA Calculation

Parameter	**Assumption**
CapEx Period	3 years
Start CapEx Year	2027
Operational Period	25 years
Distribution of Capital	
- 1st Year	10%
- 2nd Year	60%
- 3rd Year	30%
First Year of Operation	2030
Escalation of CapEx	3%
Escalation of Fixed OpEx	3%
Escalation of Variable OpEx	3%
Escalation of By-Product Revenue	3%
Discount Rate	8%

Power and Natural Gas Price Sensitivity Inputs

Natural gas was modeled as the fuel used to produce heat for the capture plant. The Alberta Energy Regulator's AECO-C price forecasts from June 2025 were used as the low, nominal, and high cases for natural gas pricing. A 3% annual escalation was applied after 2034.

Nominal power prices were estimated based on historical data, and the Alberta Electrical System Operator's supply and demand forecasts. The nominal power price was assumed to be $75.00/MWh starting in 2025. The low power price was assumed to be 80% of the nominal price. Both low and nominal pricing had 3% annual escalation applied after 2025. The high-power price assumed Alberta's rate at $120.60/MWh for 2025 and 2026, with a 3% annual escalation applied starting in 2027.

The utility pricing assumptions used in the economic sensitivity analysis are outlined below.

Table 3. Utility Pricing Assumptions

Parameter	Low Value	Nominal Value	High Value
Natural Gas Price[1]	$0.94/GJ	$2.71/GJ	$4.47/GJ
Power Price[1]	$60/MWh	$75/MWh	$120.6/MWh

[1] 3% annual inflation applies

To understand the influence of natural gas price and power price on a project's net present value (NPV), these parameters were entered into a probabilistic economic model. A discount rate of 8% was used to calculate the project's NPV, which is the sum of the project's cash flows discounted at 8%. Each of the CHP plant scenarios received the full CCUS Investment Tax Credit (ITC) based on their calculated dual-use factor.